

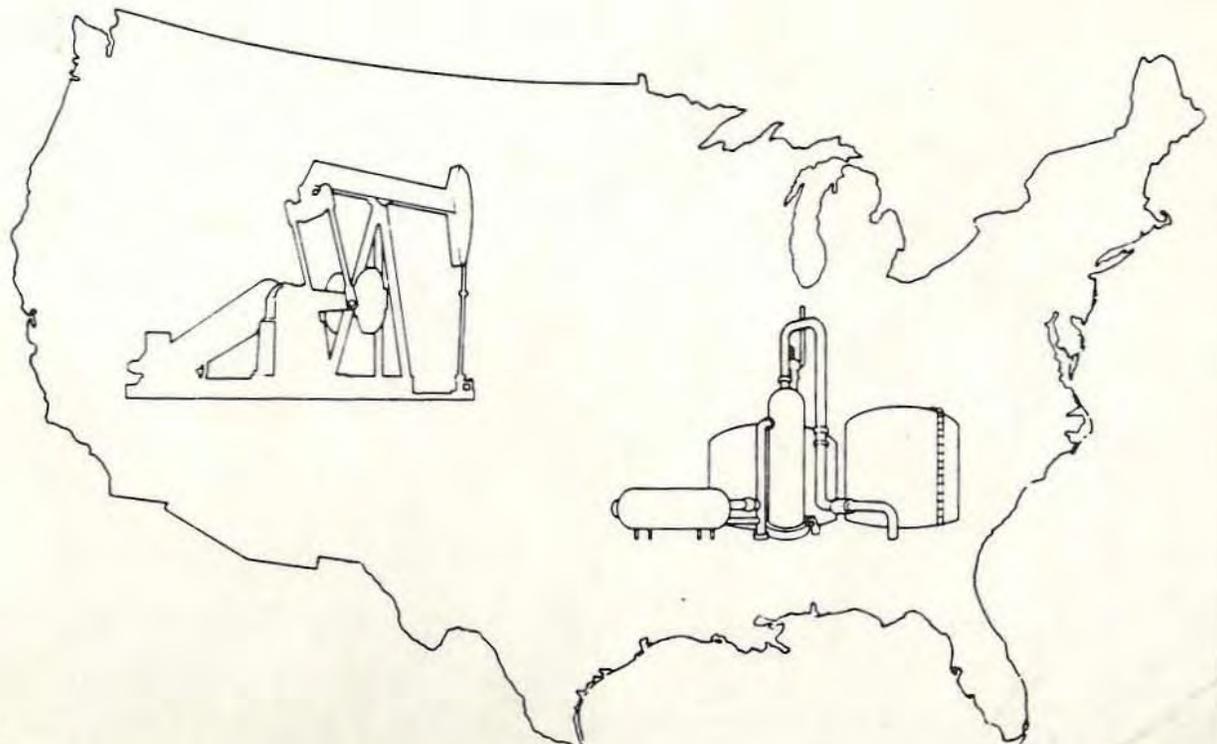
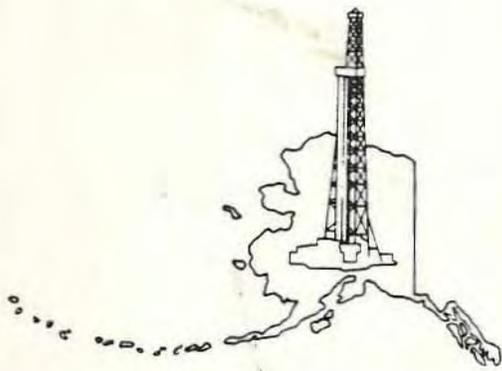


Solid Waste

Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

Volume 1 of 3
Oil and Gas



REPORT TO CONGRESS

MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY

VOLUME 1 OF 3

OIL AND GAS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Office of Solid Waste and Emergency Response
Washington, D.C. 20460

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CHAPTER I

INTRODUCTION

STATUTORY REQUIREMENTS AND GENERAL PURPOSE

Under Section 3001(b)(2)(A) of the 1980 Amendments to the Resource Conservation and Recovery Act (RCRA), Congress temporarily exempted several types of solid wastes from regulation as hazardous wastes, pending further study by the Environmental Protection Agency (EPA).¹ Among the categories of wastes exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." Section 8002(m) of the Amendments requires the Administrator to study these wastes and submit a final report to Congress. This report responds to those requirements. Because of the many inherent differences between the oil and gas industry and the geothermal energy industry, the report is submitted in three volumes. Volume 1 (this volume) covers the oil and gas industry; Volume 2 covers the geothermal energy industry; Volume 3 covers State regulatory summaries for the oil and gas industry and includes a glossary of terms. This report discusses wastes generated only by the onshore segment of the oil and gas industry.

The original deadline for this study was October 1982. EPA failed to meet that deadline, and in August 1985 the Alaska Center for the Environment sued the Agency for its failure to conduct the study.

¹ EPA is also required to make regulatory determinations affecting the oil and gas and geothermal energy industries under several other major statutes. These include designing appropriate effluent limitations guidelines under the Clean Water Act, determining emissions standards under the Clean Air Act, and implementing the requirements of the underground injection control program under the Safe Drinking Water Act.

EPA entered into a consent order, obligating it to submit the final Report to Congress on or before August 31, 1987. In April 1987, this schedule was modified and the deadline for submittal of the final Report to Congress was extended to December 31, 1987.

Following submission of the current study, and after public hearings and opportunity for comment, the Administrator of EPA must determine either to promulgate regulations under the hazardous waste management provisions of RCRA (Subtitle C) or to declare that such regulations are unwarranted. Any regulations would not take effect unless authorized by an act of Congress.

This does not mean that the recommendations of this report are limited to a narrow choice between application of full Subtitle C regulation and continuation of the current exemption. Section 8002(m) specifically requires the Administrator to propose recommendations for "[both] Federal and non-Federal actions" to prevent or substantially mitigate any adverse effects associated with management of wastes from these industries. EPA interprets this statement as a directive to consider the practical and prudent means available to avert health or environmental damage associated with the improper management of oil, gas, or geothermal wastes. The Agency has identified a wide range of possible actions, including voluntary programs, cooperative work with States to modify their programs, and Federal action outside of RCRA Subtitle C, such as RCRA Subtitle D, the existing Underground Injection Control Program under the Safe Drinking Water Act, or the National Pollution Discharge Elimination System under the Clean Water Act.

In this light, EPA emphasizes that the recommendations presented here do not constitute a regulatory determination. Such a determination cannot be made until the public has had an opportunity to review and comment on this report (i.e., the determination cannot be made until June 1988). Furthermore, the Agency is, in several important areas, presenting optional approaches involving further research and consultation with the States and other affected parties.

STUDY APPROACH

The study factors are listed in the various paragraphs of Section 8002(m), which is quoted in its entirety as Exhibit 1 (page I-13). For clarity, the Agency has designed this report to respond specifically to each study factor within separate chapters or sections of chapters. It is important to note that although every study factor has been weighed in arriving at the conclusions and recommendations of this report, no single study factor has a determining influence on the conclusions and recommendations.

The study factors are defined in the paragraphs below, which also introduce the methodologies used to analyze each study area with respect to the oil and gas industry. More detailed methodological discussions can be found later in this report and in the supporting documentation and appendices.

STUDY FACTORS

The principal study factors of concern to Congress are listed in subparagraphs (A) through (G) of Section 8002(m)(1) (see Exhibit 1). The introductory and concluding paragraphs of the Section, however, also contain directives to the Agency on the content of this study. This work has therefore been organized to respond to the following comprehensive interpretation of the 8002(m) study factors.

Study Factor 1 - Defining Exempt Wastes

RCRA describes the exempt wastes in broad terms, referring to "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." The Agency, therefore, relied to the extent possible on the legislative history of the amendments, which provides guidance on the definition of other wastes. The tentative scope of the exemption is discussed in Chapter II of this volume.

Study Factor 2 - Specifying the Sources and Volumes of Exempt Wastes

In response to Section 8002(m)(1)(A), EPA has developed estimates of the sources and volumes of all exempt wastes. The estimates are presented in Chapter II, "Overview of the Industry."

Comprehensive information on the volumes of exempt wastes from oil and gas operations is not routinely collected nationwide; however, estimates of total volumes produced can be made through a variety of approaches.

With respect to drilling muds and related wastes, two methods for estimating volumes are presented. The first, developed early in the study by EPA, estimates drilling wastes as a function of the size of reserve pits. The second method is based on a survey conducted by the American Petroleum Institute (API) on production of drilling muds and completion fluids, cuttings, and other associated wastes discharged to reserve pits. Both methods and their results are included in Chapter II.

Similarly, EPA and API developed independent estimates of produced water volumes. EPA's first estimates were based on a survey of the injection, production, and hauling reports of State agencies; API's were based on its own survey of production operations. Again, this report presents the results of both methodologies.

Study Factor 3 - Characterizing Wastes

Section 8002(m) does not directly call for a laboratory analysis of the exempted wastes, but the Agency considers such a review to be a necessary and appropriate element of this study. Analysis of the principal high-volume wastes (i.e., drilling fluids and produced waters) can help to indicate whether any of the wastes may be hazardous under the

definitions of RCRA Subtitle C. Wastes were examined with regard to whether they exhibited any of the hazardous characteristics defined under 40 CFR 261 of RCRA, including extraction procedure toxicity, ignitability, corrosivity, and reactivity. Also, a compositional analysis was performed for the purpose of determining if hazardous constituents were present in the wastes at concentrations exceeding accepted health-based limits.

EPA therefore conducted a national screening type program that sampled facilities to compile relevant data on waste characteristics. Sites were selected at random in cooperation with State regulatory agencies, based on a division of the United States into zones (see Figure I-1). Samples were subjected to extensive analysis, and the results were subjected to rigorous quality control procedures prior to their publication in January 1987. Simultaneously, using a different sampling methodology, API sampled the same sites and wastes covered by the EPA-sponsored survey. Chapter II of this report, "Overview of the Industry," presents a summary of results of both programs.

Study Factor 4 - Describing Current Disposal Practices

Section 8002(m)(1)(B) calls for an analysis of current disposal practices for exempted wastes. Chapter III, "Current and Alternative Waste Management Practices," summarizes EPA's review, which was based on a number of sources. Besides reviewing the technical literature, EPA sent representatives to regulatory agencies of the major oil- and gas-producing States to discuss current waste management technologies with State representatives. In addition, early drafts of this study's characterizations of such technologies were reviewed by State and industry representatives.

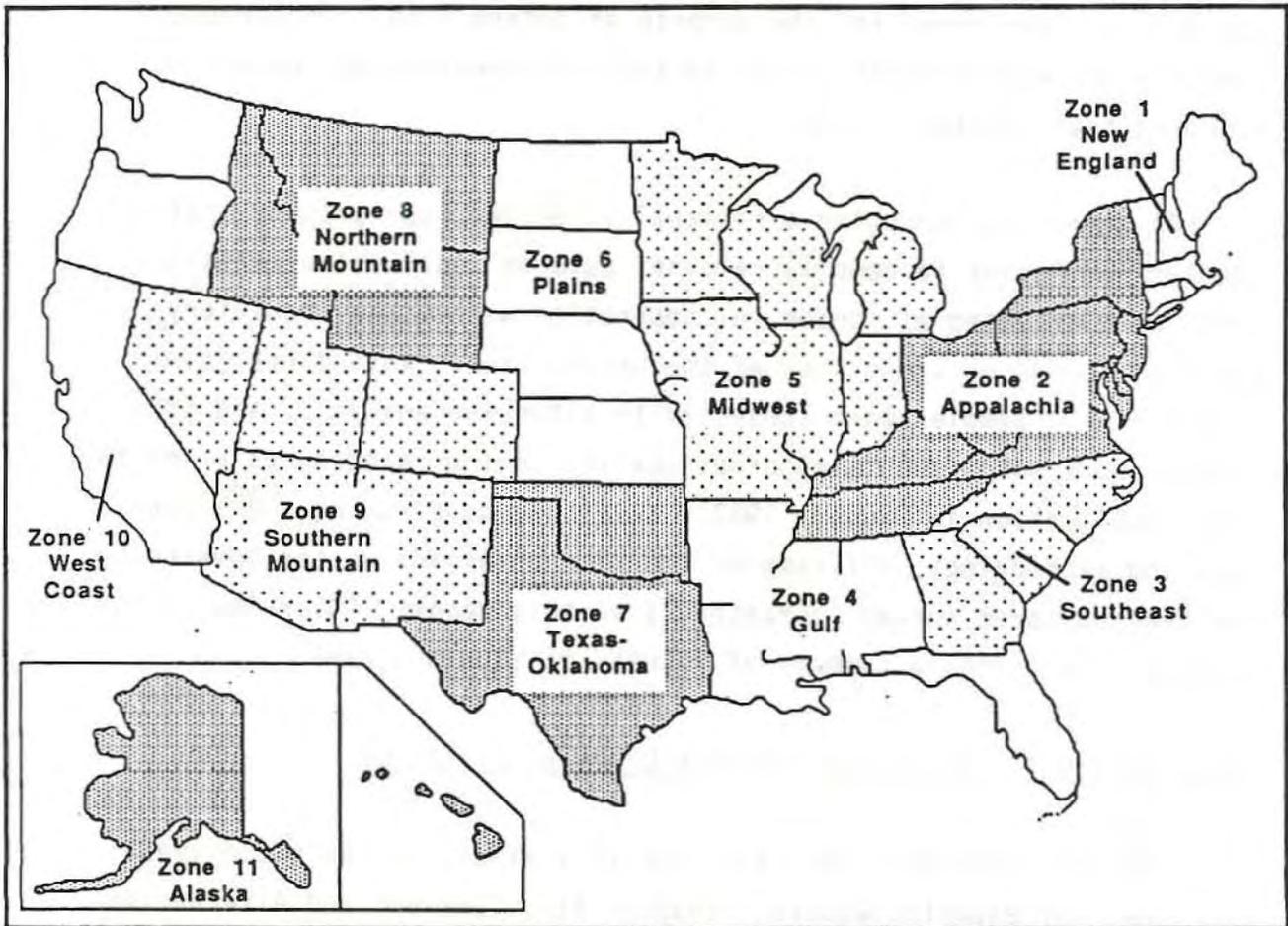


Figure I-1
Oil and Gas Production Zones
 Divisions of the United States
 Used for the
 RCRA Section 8002(m) Study of
 Oil and Gas Wastes

The Agency intentionally has not compiled an exhaustive review of waste management technologies used by the oil and gas industry. As stressed throughout this volume, conditions and methods vary widely from State to State and operation to operation. Rather, the Agency has described the principal and common methods of managing field-generated wastes and has discussed these practices in general and qualitative terms in relation to their effectiveness in protecting human health and the environment.

Study Factor 5 - Documenting Evidence of Damage to Human Health and the Environment Caused by Management of Oil and Gas Wastes

Section 8002(m)(1)(D) requires EPA to analyze "documented cases" of health and environmental damage related to surface runoff or leachate. Although EPA has followed this instruction, paragraph (1) of the section also refers to "adverse effects of such wastes [i.e., exempted wastes, not necessarily only runoff and leachate] on humans, water, air, health, welfare, and natural resources...."

Chapter IV, "Damage Cases," summarizes EPA's effort to collect documented evidence of harm to human health, the environment, or valuable resources. Cases were accepted for presentation in this report only if, prior to commencement of field work, they met the standards of the test of proof, defined as (1) a scientific study, (2) an administrative finding of damage under State or other applicable authority, or (3) determination of damage by a court. Many cases met more than one such test of proof.

A number of issues of interpretation have been raised that must be clarified at the outset. First, in the Agency's opinion, the case study approach, such as that called for by Section 8002(m), is intended only to define the nature and range of known damages, not to estimate the frequency or extent of damages associated with typical operations. The

results presented here should not be interpreted as having statistical significance. The number of cases reported in each category bears no statistically significant relationship to the actual types and distribution of damages that may or may not exist across the United States.

Second, the total number of cases bears no implied or intended relationship to the total extent of damage from oil or gas operations caused at present or in the past.

Third, Section 8002(m)(1)(D) makes no mention of defining relationships between documented damages and violations of State or other Federal regulations. As a practical necessity, EPA has in fact relied heavily on State enforcement and complaint files in gathering documentation for this section of the report.² Consequently, a large proportion of cases reported here involve violations of State regulations. However, the fact that the majority of cases presented here involve State enforcement actions implies nothing, positive or negative, about the success of State programs in enforcing their requirements on industry.

Study Factor 6 - Assessing Potential Danger to Human Health or the Environment from the Wastes

Section 8002(m)(1)(C) requires analysis of the potential dangers of surface runoff and leachate. These potential effects can involve all types of damages over a long period of time and are not necessarily limited to the categories of damages for which documentation is currently available.

² Other sources have included evidence submitted by private citizens or supplied by attorneys in response to inquiries from EPA researchers.

Several methods of estimating potential damages are available, and EPA has combined two approaches in responding to this study factor in Chapter V, "Risk Modeling." The first has been to use quantitative risk assessment modeling techniques developed for use elsewhere in the RCRA program. The second has been to apply more qualitative methods, based on traditional environmental assessment techniques.

The goal of both the quantitative and the qualitative risk assessments has been to define the most important factors in causing or averting human health risk and environmental risk from field operations. For the quantitative evaluation, EPA has adapted the EPA Liner Location Model, which was built to evaluate the impacts of land disposal of hazardous wastes, for use in analyzing drilling and production conditions. Since oil and gas operations are in many ways significantly different from land disposal of hazardous wastes, all revisions to the Liner Location Model and assumptions made in its present application have been extensively documented and are summarized in Chapter V. The procedures of traditional environmental assessment needed no modification to be applied.

As is true in the damage case work, the results of the modeling analysis have no statistical significance in terms of either the pattern or the extent of damages projected. The Agency modeled a subset of prototype situations, designed to roughly represent significant variations in conditions across the country. The results are very useful for characterizing the interactions of technological, geological, and climatic differences as they influence the potential for damages.

Study Factor 7 - Reviewing the Adequacy of Government and Private Measures to Prevent and/or Mitigate any Adverse Effects

Section 8002 (m)(1) requires that the report's conclusions of any adverse effects associated with current management of exempted wastes

include consideration of the "adequacy of means and measures currently employed by the oil and gas industry, Government agencies, and others" to dispose of or recycle wastes or to prevent or mitigate those adverse effects.

Neither the damage case assessment nor the risk assessment provided statistically representative data on the extent of damages, making it impossible to compare damages in any quantitative way to the presence and effectiveness of control efforts. The Agency's response to this requirement is therefore based on a qualitative assessment of all the materials gathered during the course of assembling the report and on a review of State regulatory programs presented in Chapter VII, "Current Regulatory Programs." Chapter VII reviews the elements of programs and highlights possible inconsistencies, lack of specificity, potential problems in implementation, or gaps in coverage. Interpretation of the adequacy of these control efforts is presented in Chapter VIII, "Conclusions."

Study Factor 8 - Defining Alternatives to Current Waste Management Practices

Section 8002 (m)(1) requires EPA to analyze alternatives to current disposal methods. EPA's discussion in response to this study factor is incorporated in Chapter III, "Current and Alternative Waste Management Practices."

Chapter III merges the concepts of current and alternative waste management practices. It does not single out particular technologies as potential substitutes for current practices because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume waste streams, no significant, field-proven, newly invented technologies that can be considered "innovative" or "emerging" are in the research or development stage.

Practices that are routine in one location may be considered innovative or alternative elsewhere. On the other hand, virtually every waste management practice that exists can be considered "current" in one specific situation or another.

This does not mean that improvements are not possible: in some cases, currently available technologies may not be properly selected, implemented, or maintained. Near-term improvements in waste management in these industries will likely be based largely on more effective use of what is already available.

Study Factor 9 - Estimating the Costs of Alternative Practices

Subparagraph (F) calls for analysis of costs of alternative practices. The first several sections of Chapter VI, "Costs and Economic Impacts of Alternative Waste Management Practices," present the Agency's analysis of this study factor.

For the purposes of this report, EPA based its cost estimates on 21 prototypical regional projects, defined so as to capture significant differences between major and independent companies and between stripper operations and other projects. The study evaluates costs of waste disposal only for the two principal high-volume waste streams of concern, drilling fluids and produced waters, employing as its baseline the use of unlined reserve pits located at the drill site and the disposal of produced waters in injection wells permitted under the Federal Underground Injection Control Program and located off site.

The study then developed two alternative scenarios that varied the incremental costs of waste management control technology, applied them to each prototype project, and modeled the cost impacts of each. The

first scenario imposes a set of requirements typical of full Subtitle C management rules; the second represents a less stringent and extensive range of requirements based, in essence, on uniform nationwide use of the most up-to-date and effective controls now being applied by any of the States. Model results indicate cumulative annual costs, at the project level, of each of the more stringent control scenarios.

Study Factor 10 - Estimating the Economic Impacts on Industry of Alternative Practices

In response to the requirements of subparagraph (G), the final two sections of Chapter VI present the Agency's analysis of the potential economic impacts of nationwide imposition of the two control scenarios analyzed at the project level.

Both the cost and the economic impact predicted in this report are admittedly large. Many significant variations influence the economics of this industry and make it difficult to generalize about impacts on either the project or the national level. In particular, the price of oil itself greatly affects both levels. Fluctuations in the price of oil over the period during which this study was prepared have had a profound influence on project economics, making it difficult to draw conclusions about the current or future impacts of modified waste management practices.

Nevertheless, the Agency believes that the analysis presented here is a reasonable response to Congress's directives, and that the results, while they cannot be exact, accurately reflect the general impacts that might be expected if environmental control requirements were made more stringent.

EXHIBIT 1:

Section 8002(m) Resource Conservation and Recovery Act as amended by PL 96-482

"(m) Drilling Fluids, Produced Waters, and Other Wastes Associated with the Extraction, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.- (1) The Administrator shall conduct a detailed and comprehensive study and submit a report on the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy on human health and the environment, including, but not limited to the effects of such wastes on humans, water, air, health, welfare, and natural resources and on the adequacy of means and measures currently employed by the oil and gas and geothermal drilling and production industry, Government agencies, and others to dispose of and utilize such wastes and to prevent or substantially mitigate such adverse effects. Such study shall include an analysis of-

"(A) the sources and volume of discarded material generated per year from such wastes;

"(B) present disposal practices:

"(C) potential danger to human health and the environment from the surface runoff or leachate;

"(D) documented cases which prove or have caused danger to human health and the environment from surface runoff or leachate;

"(E) alternatives to current disposal methods:

"(F) the cost of such alternatives; and

"(G) the impact of those alternatives on the exploration for, and development and production of, crude oil and natural gas or geothermal energy.

In furtherance of this study, the Administrator shall, as he deems appropriate, review studies and other actions of other Federal agencies concerning such wastes with a view toward avoiding duplication of effort and the need to expedite such study. The Administrator shall publish a report of such and shall include appropriate findings and recommendations for Federal and non-Federal actions concerning such effects.

"(2) The Administrator shall complete the research and study and submit the report required under paragraph (1) not later than twenty-four months from the date of enactment of the Solid Waste Disposal Act Amendments of 1980. Upon completion of the study, the Administrator shall prepare a summary of the findings of the study, a plan for research, development, and demonstration respecting the findings of the study, and shall submit the findings and the study, along with any recommendations resulting from such study, to the Committee on Environment and Public Works of the United States Senate and the Committee on Interstate and Foreign Commerce of the United States House of Representatives.

"(3) There are authorized to be appropriations not to exceed \$1,000,000 to carry out the provisions of this subsection.

CHAPTER II

OVERVIEW OF THE INDUSTRY

DESCRIPTION OF THE OIL AND GAS INDUSTRY

The oil and gas industry explores for, develops, and produces petroleum resources. In 1985 there were approximately 842,000 producing oil and gas wells in this country, distributed throughout 38 States. They produced 8.4 million barrels¹ of oil, 1.6 million barrels of natural gas liquids, and 44 billion cubic feet of natural gas daily. The American Petroleum Institute estimates domestic reserves at 28.4 billion barrels of oil, 7.9 billion barrels of natural gas liquids, and 193 trillion cubic feet of gas. Petroleum exploration, development, and production industries employed approximately 421,000 people in 1985.²

The industry is as varied as it is large. Some aspects of exploration, development, and production can change markedly from region to region and State to State. Well depths range from as little as 30 to 50 feet in some areas to over 30,000 feet in areas such as the Anadarko Basin of Oklahoma. Pennsylvania has been producing oil for 120 years; Alaska for only 15. Maryland has approximately 14 producing wells; Texas has 269,000 and completed another 25,721 in 1985 alone. Production from a single well can vary from a high of about 11,500 barrels per day (the 1985 average for wells on the Alaska North Slope) to less than 10 barrels per day for many thousands of "stripper" wells located in Appalachia and

¹ Crude oil production has traditionally been expressed in barrels. A barrel is equivalent to 5.61 ft³, 0.158 m³, or 42 U.S. gallons.

² These numbers, provided to EPA by the Bureau of Land Management (BLM), are generally accepted.

the more developed portions of the rest of the country.³ Overall, 70 percent of all U.S. oil wells are strippers, operating on the margins of profitability. Together, however, these strippers contribute 14 percent of total U.S. production--a number that appears small, yet is roughly the equivalent of the immense Prudhoe Bay field in Alaska.

Such statistics make it clear that a short discussion such as this cannot provide a comprehensive or fully accurate description of this industry. The purpose of this chapter is simply to present the terminology used in the rest of this report⁴ and to provide an overview of typical exploration, development, and production methods. With this as introduction, the chapter then defines which oil and gas wastes EPA considers to be exempt within the scope of RCRA Section 8002; estimates the volumes of exempt wastes generated by onshore oil and gas operations; and presents the results of sample surveys conducted by EPA and the American Petroleum Institute to characterize the content of exempt oil and gas wastes.

Exploration and Development

Although geological and geophysical studies provide information concerning potential accumulations of petroleum, the only method that can confirm the presence of petroleum is exploratory drilling. The majority of exploratory wells are "dry" and must be plugged and abandoned. When an exploratory well does discover a commercial deposit, however, many development wells are typically needed to extract oil or gas from that reservoir.

³ The definition of "stripper" well may vary from State to State. For example, North Dakota defines a stripper as a well that produces 10 barrels per day or less at 6,000 feet or less; 11 to 15 barrels per day from a depth of 6,001 feet to 10,000 feet; and 16 to 20 barrels per day for wells that are 10,000 feet deep.

⁴ A glossary of terms is also provided in Volume 3.

Exploratory and development wells are mechanically similar and generate similar wastes up to the point of production. In order to bring a field into production, however, development wells generate wastes associated with well completion and stimulation; these processes are discussed below. From 1981 to 1985, exploration and development drilling combined averaged 73,000 wells per year (API 1986). Drilling activity declined in 1986 and by mid-1987 rebounded over 1986 levels.

In the early part of the century, cable-tool drilling was the predominant method of well drilling. The up-and-down motion of a chisel-like bit, suspended by a cable, causes it to chip away the rock, which must be periodically removed with a bailer. Although an efficient technique, cable-tool drilling is limited to use in shallow, low-pressure reservoirs. Today, cable-tool drilling is used on a very limited basis in the United States, having been replaced almost entirely by rotary drilling.

Rotary drilling provides a safe method for controlling high-pressure oil/gas/water flows and allows for the simultaneous drilling of the well and removal of cuttings, making it possible to drill wells over 30,000 feet deep. Figure II-1 illustrates the process. The rotary motion provided by mechanisms on the drill rig floor turns a drill pipe or stem, thereby causing a bit on the end of the pipe to gouge and chip away the rock at the bottom of the hole. The bit itself generally has three cone-shaped wheels tipped with hardened teeth and is weighted into place by thick-walled collars. Well casing is periodically cemented into the hole, providing a uniform and stable conduit for the drill stem as it drills deeper into the hole. The casing also seals off freshwater aquifers, high-pressure zones, and other troublesome formations.

Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The

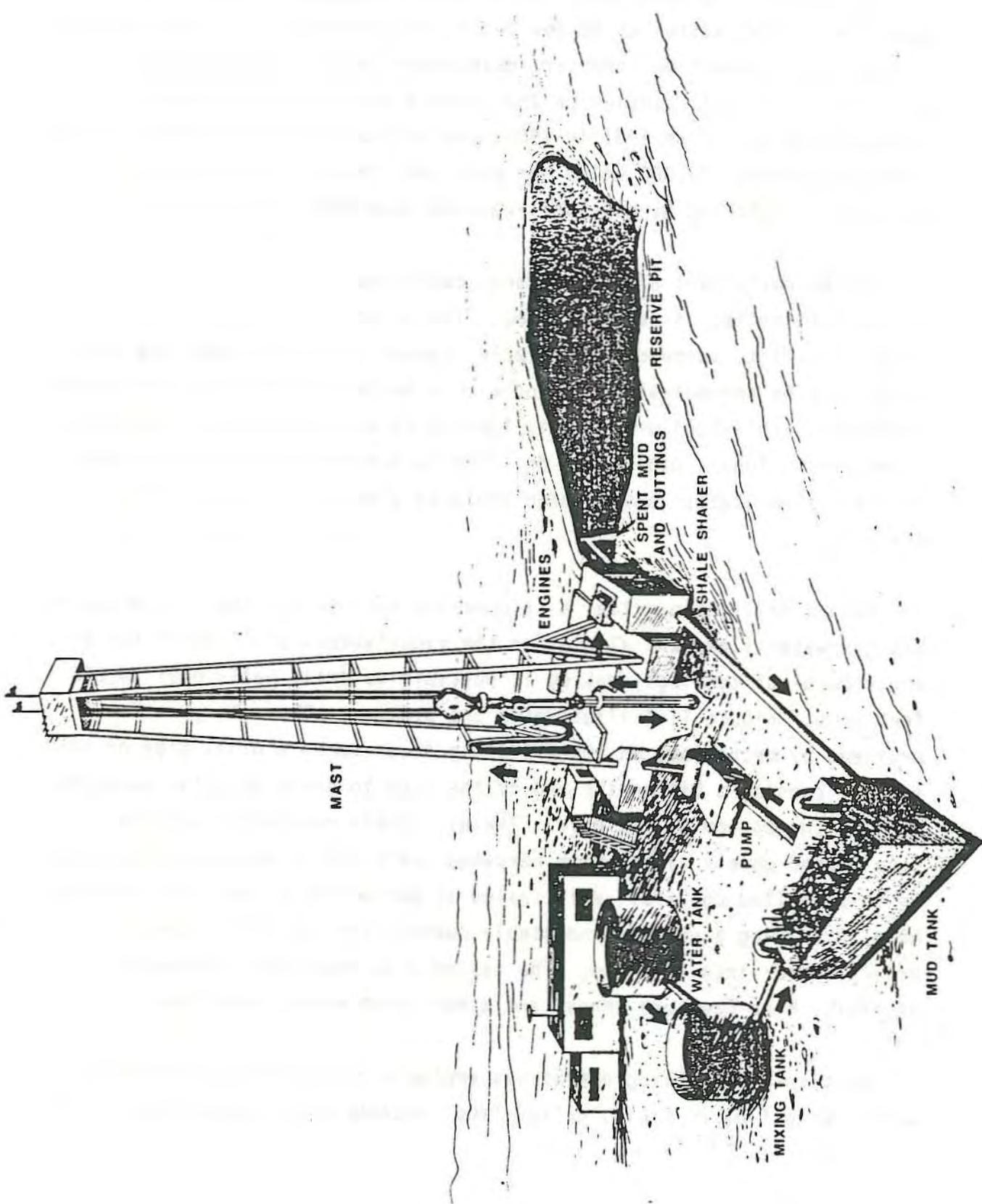


Figure II-1 Typical Rotary Drilling Rig

mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. The mud and cuttings are then pumped back up through the annular space between the drill pipe and the walls of the hole or casing. Mud is generally mixed with a weighting agent such as barite, and other mud additives, thus helping it serve several other important functions: (1) stabilizing the wellbore and preventing cave-ins, (2) counterbalancing any high-pressure oil, gas, or water zones in the formations being drilled, and (3) providing a medium to alleviate problems "downhole" (such as stuck pipe or lost circulation).

Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. The reclaimed drilling mud is then recirculated back to the well. The type and extent of solids control equipment used influences how well the cuttings can be separated from the drilling fluid, and hence influences the volume of mud discharged versus how much is recirculated. Drilling mud must be disposed of when excess mud is collected, when changing downhole conditions require a whole new mud formulation, or when the well is abandoned. The reserve pit is generally used for this purpose. (Reserve pits serve multiple waste management functions. See discussion in Chapter III.) If the well is a dry hole, the drilling mud may be disposed of downhole upon abandonment.

The formation of a drilling mud for a particular job depends on types of geologic formations encountered, economics, availability, problems encountered downhole, and well data collection practices. Water-based drilling muds predominate in the United States. Colloidal materials, primarily bentonitic clay, and weighting materials, such as barite, are common constituents. Numerous chemical additives are available to give the mud precise properties to facilitate the drilling of the well; they include acids and bases, salts, corrosion inhibitors, viscosifiers,

dispersants, fluid loss reducers, lost circulation materials, flocculants, surfactants, biocides, and lubricants. (See also Table III-2.)

Oil-based drilling fluids account for approximately 3 to 10 percent of the total volume of drilling fluids used nationwide. The oil base may consist of crude oil, refined oil (usually fuel oil or diesel), or mineral oil. Oil-based drilling fluid provides lubrication in directionally drilled holes, high-temperature stability in very deep holes, and protection during drilling through water-sensitive formations.

In areas where high-pressure or water-bearing formations are not anticipated, air drilling is considerably faster and less expensive than drilling with water- or oil-based fluids. (Air drilling cannot be used in deep wells.) In this process, compressed air takes the place of mud, cooling the bit and lifting the cuttings back to the surface. Water is injected into the return line for dust suppression, creating a slurry that must be disposed of. In the United States, air drilling is most commonly used in the Appalachian Basin, in southeastern Kansas/northeastern Oklahoma, and in the Four Corners area of the Southwest. Other low-density drilling fluids are used in special situations. Gases other than air, usually nitrogen, are sometimes useful. These may be dispersed with liquids or solids, creating wastes in the form of mist, foam, emulsion, suspension, or gel.

Potential producing zones are commonly measured and analyzed (logged) during drilling, a process that typically generates no waste. If hydrocarbons appear to be present, a drill stem test can tell much about their characteristics. When the test is completed, formation fluids collected in the drill pipe must be disposed of.

If tests show that commercial quantities of oil and gas are present, the well must be prepared for production or "completed." "Cased hole"

completions are the most common type. First, production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. Actual completion involves the use of a gun or explosive charge that perforates the production casing and begins the flow of petroleum into the well.

During these completion operations, drilling fluid in the well may be modified or replaced by specialized fluids to control flow from the formation. A typical completion fluid consists of a brine solution modified with petroleum products, resins, polymers, and other chemical additives. When the well is produced initially, the completion fluid may be reclaimed or treated as a waste product that must be disposed of. For long-term corrosion protection, a packer fluid is placed into the casing/tubing annulus. Solids-free diesel oil, crude oil, produced water, or specially treated drilling fluid are preferred packer fluids.

Following well completion, oil or gas in the surrounding formations frequently is not under sufficient pressure to flow freely into the well and be removed. The formation may be impacted with indigenous material, the area directly surrounding the borehole may have become packed with cuttings, or the formation may have inherent low permeability.

Operators use a variety of stimulation techniques to correct these conditions and increase oil flow. Acidizing introduces acid into the production formation, dissolving formation matrix and thereby enlarging existing channels in carbonate-bearing rock. Hydraulic fracturing involves pumping specialized fluids carrying sand, glass beads, or similar materials into the production formation under high pressure; this creates fractures in the rock that remain propped open by the sand, beads, or similar materials when pressure is released.

Other specialized fluids may be pumped down a production well to enhance its yield; these can include corrosion inhibitors, surfactants, friction reducers, complexing agents, and cleanup additives. Although the formation may retain some of these fluids, most are returned to the surface when the well is initially produced or are slowly released over time. These fluids may require disposal, independent of disposal associated with produced water.

Drilling operations have the potential to create air pollution from several sources. The actual drilling equipment itself is typically run by large diesel engines that tend to emit significant quantities of particulates, sulfur oxides, and oxides of nitrogen, which are subject to regulation under the Clean Air Act. The particulates emitted may contain heavy metals as well as polycyclic organic matter (POMs). Particularly for deep wells, which require the most power to drill, and in large fields where several drilling operations may be in progress at the same time, cumulative diesel emissions can be important. Oil-fired turbines are also used as a source of power on newer drilling rigs. Other sources of air pollution include volatilization of light organic compounds from reserve pits and other holding pits that may be in use during drilling; these are exempt wastes. These light organics can be volatilized from recovered hydrocarbons or from solvents or other chemicals used in the production process for cleaning, fracturing, or well completion. The volume of volatile organic compounds is insignificant in comparison to diesel engine emissions.

Production

Production operations generally include all activities associated with the recovery of petroleum from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary, secondary, and tertiary recovery methods; well workovers; and well stimulation activities. Activities associated with

surface operations include oil/gas/water separation, fluid treatment, and disposal of produced water. Each of these terms is discussed briefly below.

Downhole Operations

Primary recovery refers to the initial production of oil or gas from a reservoir using natural pressure or artificial lift methods, such as surface or subsurface pumps and gas lift, to bring it out of the formation and to the surface. Most reservoirs are capable of producing oil and gas by primary recovery methods alone, but this ability declines over the life of the well. Eventually, virtually all wells must employ some form of secondary recovery, typically involving injection of gas or liquid into the reservoir to maintain pressure within the producing formation. Waterflooding is the most frequently employed secondary recovery method. It involves injecting treated fresh water, seawater, or produced water into the formation through a separate well or wells.

Tertiary recovery refers to the recovery of the last portion of the oil that can be economically produced. Chemical, physical, and thermal methods are available and may be used in combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery involves injection of gases, such as carbon dioxide and natural gas, which combine with the oil. Thermal recovery methods include steam injection and in situ combustion (or "fire flooding"). When oil eventually reaches a production well, injected gases or fluids from secondary and tertiary recovery operations may be dissolved or carried in formation oil or water, or simply mixed with them; their removal is discussed below in conjunction with surface production operations.

Workovers, another aspect of downhole production operations, are designed to restore or increase production from wells whose flows are

inhibited by downhole mechanical failures or blockages, such as sand or paraffin deposits. Fluids circulated into the well for this purpose must be compatible with the formation and must not adversely affect permeability. They are similar to completion fluids, described earlier. When the well is put back into production, the workover fluid may be reclaimed or disposed of.

Other chemicals may be periodically or continuously pumped down a production well to inhibit corrosion, reduce friction, or simply keep the well flowing. For example, methanol may be pumped down a gas well to keep it from becoming plugged with ice.

Surface Operations

Surface production operations generally include gathering of the produced fluids (oil, gas, gas liquids, and water) from a well or group of wells and separation and treatment of the fluids. See Figures II-2, II-3, and II-4. As producing reservoirs are depleted, their water/oil ratios may increase steeply. New wells may produce little if any water; stripper wells may vary greatly in the volume of water they produce. Some may produce more than 100 barrels of water for every barrel of oil, particularly if the wells are subject to waterflooding operations.

Virtually all of this water must be removed before the product can be transferred to a pipeline. (The maximum water content allowed is generally less than 1 percent.) The oil may also contain completion or workover fluids, stimulation fluids, or other chemicals (biocides, fungicides) used as an adjunct to production. Some oil/water mixtures may be easy to separate, but others may exist as fine emulsions that do

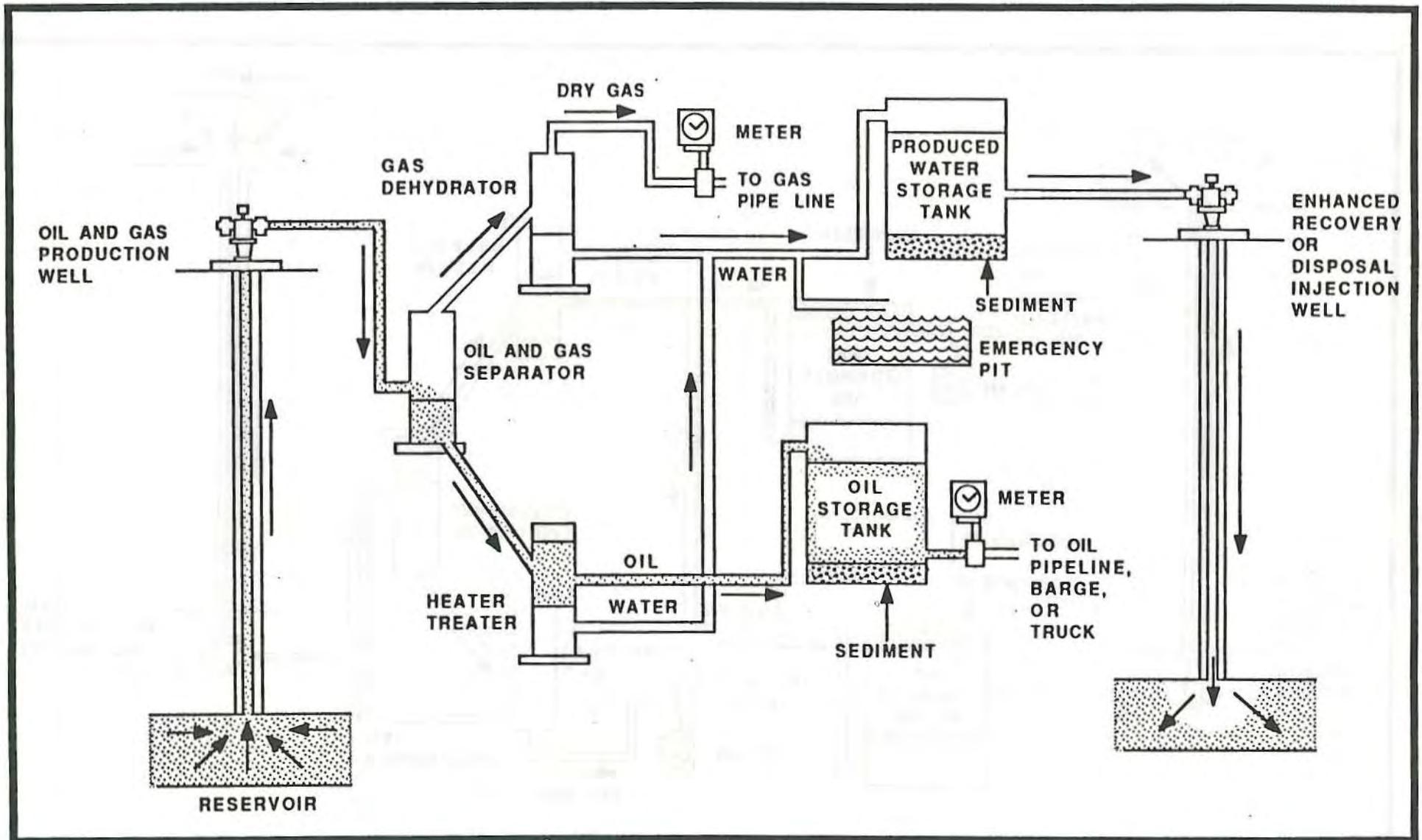


Figure II-2 Typical Production Operation, Showing Separation of Oil, Gas, and Water

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

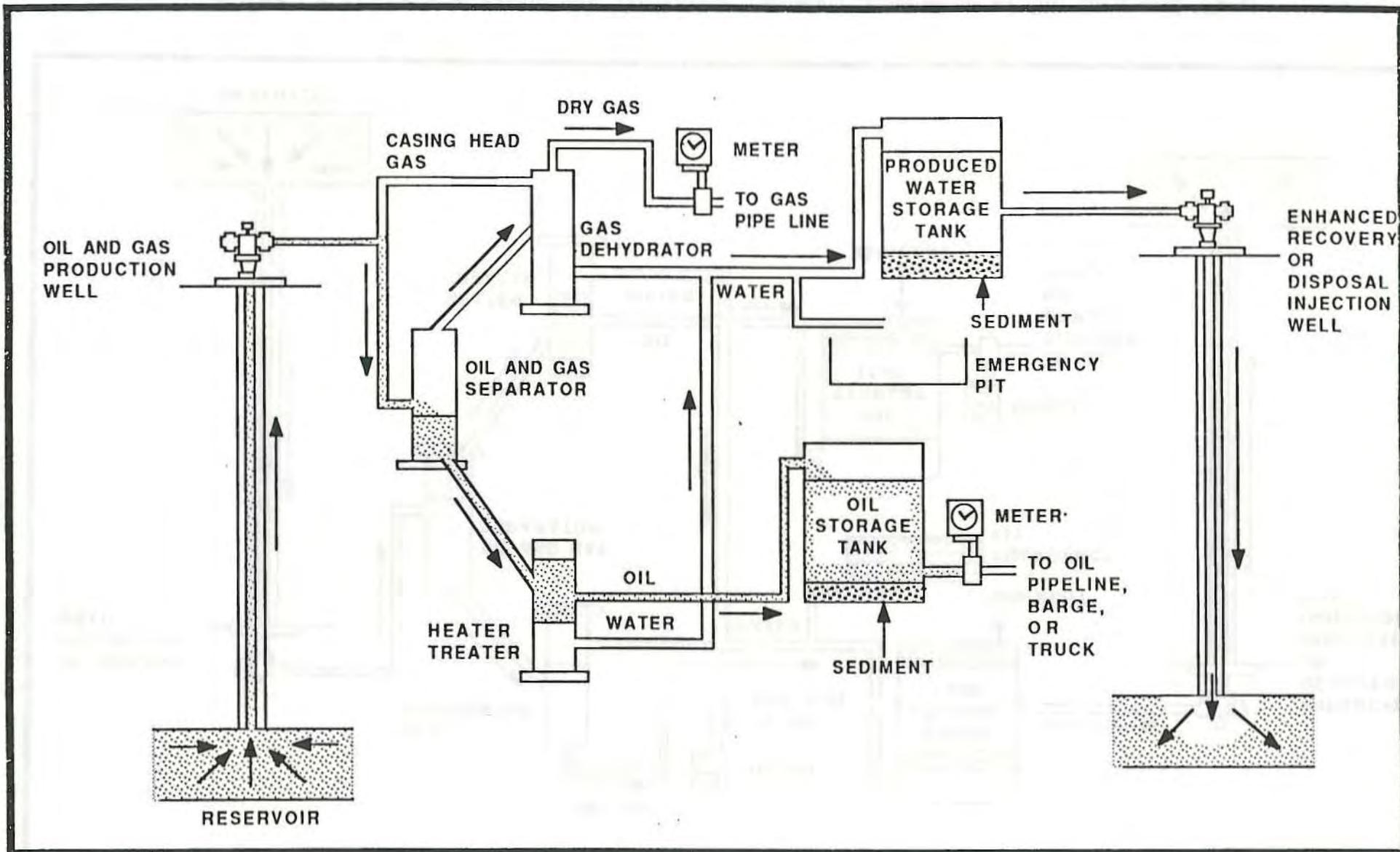


Figure II-3 Oil Production With Average H_2O Production With Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

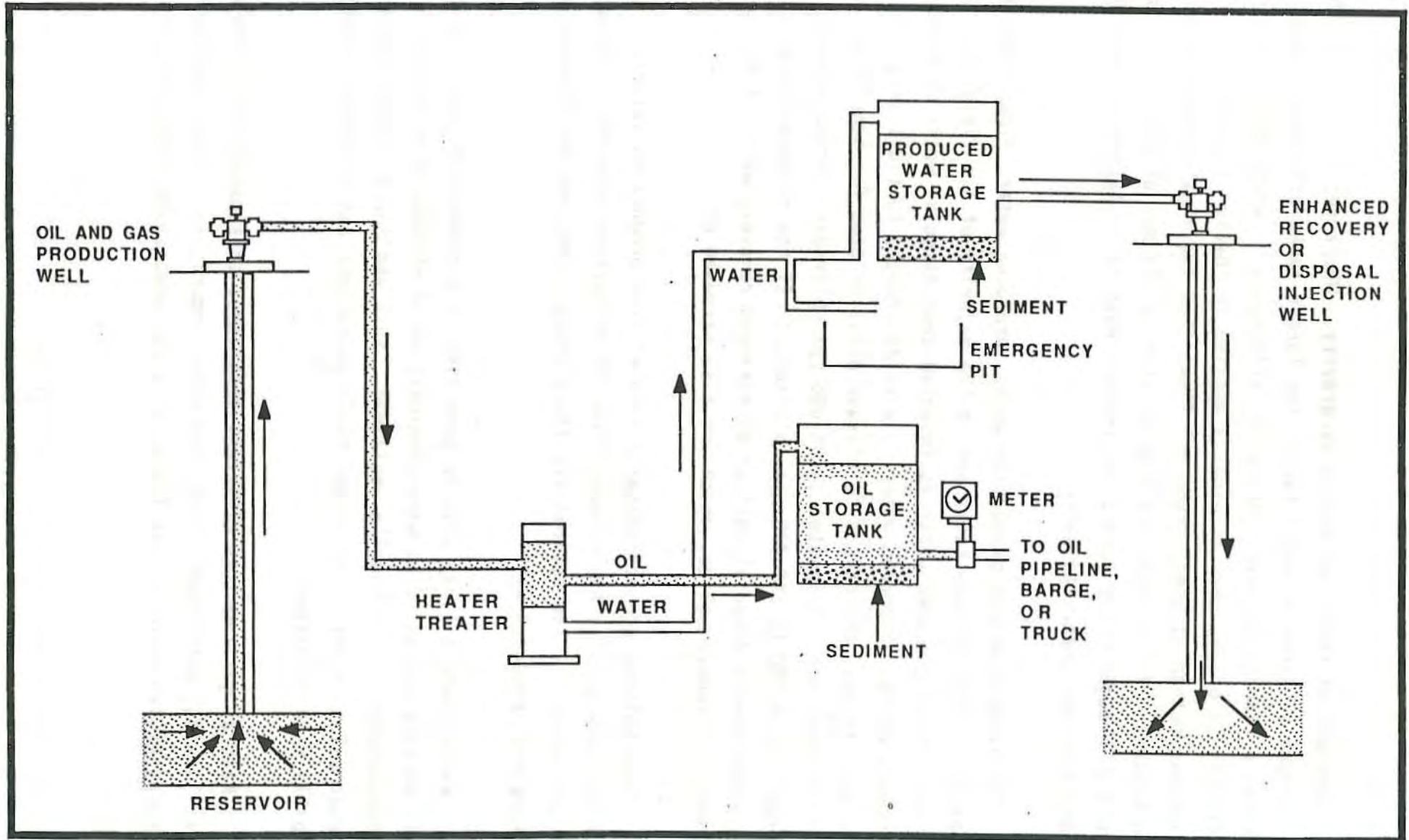


Figure II-4 High Oil/H₂O Ratio Without Significant Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

not separate of their own accord by gravity. Where settling is possible, it is done in large or small tanks, the larger tanks affording longer residence time to increase separation efficiency. Where emulsions are difficult to break, heat is usually applied in "heater treaters." Whichever method is used, crude oil flows from the final separator to stock tanks. The sludges and liquids that settle out of the oil as tank bottoms throughout the separation process must be collected and discarded along with the separated water.

The largest volume production waste, produced water, flows from the separators into storage tanks and in the majority of oil fields is highly saline. Most produced water is injected down disposal wells or enhanced recovery wells. Produced water is also discharged to tidal areas and surface streams, discharged to storage pits, or used for beneficial or agricultural use. (Seawater is 35,000 ppm chlorides. Produced water can range from 5,000 to 180,000 ppm chlorides.) If the produced water is injected down a disposal well or an enhanced recovery well, it may be treated to remove solids, which are also disposed of.

Tank bottoms are periodically removed from production vessels. Tank bottoms are usually hauled away from the production site for disposal. Occasionally, if the bottoms are fluid enough, they may be disposed of along with produced water.

Waste crude oil may also be generated at a production site. If crude oil becomes contaminated with chemicals or is skimmed from surface impoundments, it is usually reclaimed. Soil and gravel contaminated by crude oil as a result of normal field operations and occasional leaks and spills require disposal.

Natural gas requires different techniques to separate out crude oil, gas liquids, entrained solids, and other impurities. These separation processes can occur in the field, in a gas processing plant, or both, but

more frequently occur at an offsite processing plant. Crude oil, gas liquids, some free water, and entrained solids can be removed in conventional separation vessels. More water may be removed by any of several dehydration processes, frequently through the use of glycol, a liquid dessicant, or various solid dessicants. Although these separation media can generally be regenerated and used again, they eventually lose their effectiveness and must be disposed of.

Both crude oil and natural gas may contain the highly toxic gas hydrogen sulfide, which is an exempt waste. (Eight hundred ppm in air is lethal to humans and represents an occupational hazard, but not an ambient air toxics threat to human health offsite.) At plants where hydrogen sulfide is removed from natural gas, sulfur dioxide (SO_2) release results. (EPA requires compliance with the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide; DOI also has authority to regulate these emissions.) Sulfur is often recovered from the hydrogen sulfide (H_2S) as a commercial byproduct. H_2S dissolved in crude oil does not pose any danger, but when it is produced at the wellhead in gaseous form, it poses serious occupational risks through possible leaks or blowouts. These risks are also present later in the production process when the H_2S is separated out in various "sweetening" processes. The amine, iron sponge, and selexol processes are three examples of commercial processes for removing acid gases from natural gas. Each H_2S removal process results in spent or waste separation media, which must be disposed of. EPA did not sample hydrogen sulfide and sulphur dioxide emissions because of their relatively low volume and infrequency of occurrence.

Gaseous wastes are generated from a variety of other production-related operations. Volatile organic compounds may also be released from minute leaks in production equipment or from pressure vents on separators and storage tanks. When a gas well needs to be cleaned out, it may be produced wide open and vented directly to the atmosphere.

Emissions from volatile organic compounds are exempt under Section 3001(b)(2)(A) of RCRA and represent a very low portion of national air emissions. Enhanced oil recovery steam generators may burn crude oil as fuel, thereby creating air emissions. These wastes are nonexempt.

DEFINITION OF EXEMPT WASTES

The following discussion presents EPA's tentative definition of the scope of the exemption.

Scope of the Exemption

The current statutory exemption originated in EPA's proposed hazardous waste regulations of December 18, 1978 (43 FR 58946). Proposed 40 CFR 250.46 contained standards for "special wastes"--reduced requirements for several types of wastes that are produced in large volume and that EPA believed may be lower in toxicity than other wastes regulated as hazardous wastes under RCRA. One of these categories of special wastes was "gas and oil drilling muds and oil production brines."

In the RCRA amendments of 1980, Congress exempted most of these special wastes from the hazardous waste requirements of RCRA Subtitle C, pending further study by EPA. The oil and gas exemption, Section 3001(b)(2)(A), is directed at "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas." The legislative history does not elaborate on the definition of drilling fluids or produced waters, but it does discuss "other wastes" as follows:

The term "other wastes associated" is specifically included to designate waste materials intrinsically derived from the primary field operations associated with the exploration, development, or production of crude oil and natural gas. It would cover such substances as: hydrocarbon bearing soil in and around related facilities; drill cuttings; and materials (such as hydrocarbons,

water, sand and emulsion) produced from a well in conjunction with crude oil and natural gas and the accumulated material (such as hydrocarbons, water, sand, and emulsion) from production separators, fluid treating vessels, storage vessels, and production impoundments. (H.R. Rep No. 1444, 96th Cong., 2d Sess. at 32 (1980)).

The phrase "intrinsically derived from the primary field operations..." is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.

In order to arrive at a clear working definition of the scope of the exemption under Section 8002(m), EPA has used these statements in conjunction with the statutory language of RCRA as a basis for making the following assumptions about which oil and gas wastes should be included in the present study.

- Although the legislative history underlying the oil and gas exemption is limited to "other wastes associated with the exploration development or production of crude oil or natural gas," the Agency believes that the rationale set forth in that history is equally applicable to produced waters and drilling fluids. Therefore, in developing criteria to define the scope of the Section 3001(b)(2) exemption, the Agency has applied this legislative history to produced waters and drilling fluids.
- The potential exists for small volume nonexempt wastes to be mixed with exempt wastes, such as reserve pit contents. EPA believes it is desirable to avoid improper disposal of hazardous (nonexempt) wastes through dilution with nonhazardous exempt wastes. For example, unused pipe dope should not be disposed of in reserve pits. Some residual pipe dope, however, will enter the reserve pit as part of normal field operations; this residual pipe dope does not concern EPA. EPA is undecided as to the proper disposal method for some other waste streams, such as rigwash that often are disposed of in reserve pits.

Using these assumptions, the test of whether a particular waste qualifies under the exemption can be made in relation to the following three separate criteria. No one criterion can be used as a standard when defining specific waste streams that are exempt. These criteria are as follows.

1. Exempt wastes must be associated with measures (1) to locate oil or gas deposits, (2) to remove oil or natural gas from the ground, or (3) to remove impurities from such substances, provided that the purification process is an integral part of primary field operations.⁵
2. Only waste streams intrinsic to the exploration for, or the development and production of, crude oil and natural gas are subject to exemption. Waste streams generated at oil and gas facilities that are not uniquely associated with the exploration, development, or production activities are not exempt. (Examples would include spent solvents from equipment cleanup or air emissions from diesel engines used to operate drilling rigs.)

Clearly those substances that are extracted from the ground or injected into the ground to facilitate the drilling, operation, or maintenance of a well or to enhance the recovery of oil and gas are considered to be uniquely associated with primary field operations. Additionally, the injection of materials into the pipeline at the wellhead which keep the lines from freezing or which serve as solvents to prevent paraffin accumulation is intrinsically associated with primary field operations. With regard to injection for enhanced recovery, the injected materials must function primarily to enhance recovery of oil and gas and must be recognized by the Agency as being appropriate for enhanced recovery. An example would be produced water. In this context, "primarily functions" means that the main reason for injecting the materials is to enhance recovery of oil and gas rather than to serve as a means for disposing of those materials.

3. Drilling fluids, produced waters, and other wastes intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy are subject to exemption. Primary field operations encompass production-related activities but not transportation or manufacturing activities. With respect to oil production, primary field operations encompass those activities occurring at or near the wellhead, but prior to the transport of oil from an individual field facility or a centrally located facility to a carrier (i.e., pipeline or trucking concern) for transport to a refinery or to a refiner. With respect to natural gas production, primary field operations are those activities occurring at or near the wellhead or at the gas plant but prior to that point at which the gas is transferred from an individual field facility, a centrally located facility, or a gas plant to a carrier for transport to market.

⁵ Thus, wastes associated with such processes as oil refining, petrochemical-related manufacturing, or electricity generation are not exempt because those processes do not occur at the primary field operations.

Primary field operations may encompass the primary, secondary, and tertiary production of oil or gas. Wastes generated by the transportation process itself are not exempt because they are not intrinsically associated with primary field operations. An example would be pigging waste from pipeline pumping stations.

Transportation for the oil and gas industry may be for short or long distances. Wastes associated with manufacturing are not exempt because they are not associated with exploration, development, or production and hence are not intrinsically associated with primary field operations. Manufacturing (for the oil and gas industry) is defined as any activity occurring within a refinery or other manufacturing facility the purpose of which is to render the product commercially saleable.

Using these definitions, Table II-1 presents definitions of exempted wastes as defined by EPA for the purposes of this study. Note that this is a partial list only. Although it includes all the major streams that EPA has considered in the preparation of this report, others may exist. In that case, the definitions listed above would be applied to determine their status under RCRA.

Waste Volume Estimation Methodology

Information concerning volumes of wastes from oil and gas exploration, development, and production operations is not routinely collected nationwide, making it necessary to develop methods for estimating these volumes by indirect methods in order to comply with the Section 8002(m) requirement to present such estimates to Congress. For this study, estimates were compiled independently by EPA and by the American Petroleum Institute (API) using different methods. Both are discussed below.

Estimating Volumes of Drilling Fluids and Cuttings

EPA considered several different methodologies for determining volume estimates for produced water and drilling fluid.

Table II-1 Partial List of Exempt and Nonexempt Wastes

EXEMPT WASTES

Drill cuttings	Basic sediment and water and other tank bottoms from storage facilities and separators	Appropriate fluids injected downhole for secondary and tertiary recovery operations
Drilling fluids		
Well completion, treatment, and stimulation fluids	Produced water	Liquid hydrocarbons removed from the production stream but not from oil refining
Packing fluids	Constituents removed from produced water before it is injected or otherwise disposed of	Gases removed from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons
Sand, hydrocarbon solids, and other deposits removed from production wells		
Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment	Accumulated materials (such as hydrocarbons, solids, sand, and emulsion) from production separators, fluid-treating vessels, and production impoundments that are not mixed with separation or treatment media	Materials ejected from a production well during the process known as blowing down a well
Hydrocarbon-bearing soil		Waste crude oil from primary field operations
Pigging wastes from gathering lines		Light organics volatilized from recovered hydrocarbons or from solvents or other chemicals used for cleaning, fracturing, or well completion
Wastes from subsurface gas storage and retrieval	Drilling muds from offshore operations	

NONEXEMPT WASTES

Waste lubricants, hydraulic fluids, motor oil, and paint	Sanitary wastes, trash, and gray water	Waste iron sponge, glycol, and other separation media
Waste solvents from clean-up operations	Gases, such as SO _x , NO _x , and particulates from gas turbines or other machinery	Filters Spent catalysts
Off-specification and unused materials intended for disposal	Drums (filled, partially filled, or cleaned) whose contents are not intended for use	Wastes from truck- and drum-cleaning operations
Incinerator ash		Waste solvents from equipment maintenance
Pigging wastes from transportation pipelines		Spills from pipelines or other transport methods

Table II-1

EPA's estimates: For several regions of the country, estimates of volumes of drilling fluids and cuttings generated from well drilling operations are available on the basis of waste volume per foot of well drilled. Estimates range from 0.2 barrel/foot (provided by the West Virginia Dept. of Natural Resources) to 2.0 barrels/foot (provided by NL Baroid Co. for Cotton Valley formation wells in Panola County, Texas). EPA therefore considered the possibility of using this approach nationwide. If it were possible to generate such estimates for all areas of the country, including allowances for associated wastes such as completion fluids and waste cement, nationwide figures would then be comparatively easy to generate. They could be based on the total footage of all wells drilled in the U.S., a statistic that is readily available from API.

This method proved infeasible, however, because of a number of complex factors contributing to the calculation of waste-per-foot estimates that would be both comprehensive and valid for all areas of the country. For instance, the use of solids control equipment at drilling sites, which directly affects waste generation, is not standardized. In addition, EPA would have to differentiate among operations using various drilling fluids (oil-based, water-based, and gas-based fluids). These and other considerations caused the Agency to reject this method of estimating volumes of drilling-related wastes.

Another methodology would be to develop a formal model for estimating waste volumes based on all the factors influencing the volume of drilling waste produced. These factors would include total depth drilled, geologic formations encountered, drilling fluid used, solids control equipment used, drilling problems encountered, and so forth. Such a model could then be applied to a representative sample of wells drilled nationwide, yielding estimates that could then be extrapolated to produce nationwide volumes estimates.

This method, too, was rejected as infeasible. It would have required access to data derived from the driller's logs and mud logs maintained at individual well sites, which would have been very difficult to acquire. Beyond this, other data and analytical needs for building such a model proved to be beyond the resources available for the project.

With these methodologies unavailable, EPA developed its estimates by equating the wastes generated from a drilling operation with the volume of the reserve pit constructed to service the well. Typically, each well is served by a single reserve pit, which is used primarily for either temporary or permanent disposal of drilling wastes. Based on field observations, EPA made the explicit assumption that reserve pits are sized to accept the wastes anticipated from the drilling operation. The Agency then collected information on pit sizes during the field sampling program in 1986 (discussed later in this chapter), from literature searches, and by extensive contact with State and Federal regulatory personnel.

EPA developed three generic pit sizes (1,984-, 22,700-, and 87,240-barrel capacity) to represent the range of existing pits and assigned each State a percent distribution for each pit size based on field observation and discussion with selected State and industry personnel. For example, from the data collected, Utah's drilling sites were characterized as having 35 percent small pits, 50 percent medium pits, and 15 percent large pits. Using these State-specific percent distributions, EPA was then able to readily calculate an estimate of annual drilling waste volumes per year for each State. Because Alaska's operations are generally larger than operations in the other oil- and gas-producing States, Alaska's generic pit sizes were different (55,093- and 400,244-barrel capacity.)

Although the EPA method is relatively simple, relying on a well site feature that is easily observable (namely, the reserve pit), the method does have several disadvantages. It does not explicitly account for waste volume increases and decreases due to evaporation, percolation, and rainwater collection. The three generic pit sizes may not adequately represent the wide range of pit sizes used for drilling, and they all assume that the total volume of each reserve pit, minus a nominal 2 feet of freeboard, will be used for wastes. Finally, the information collected to determine the percent distributions of pit sizes within States may not adequately characterize the industry, and adjusting the distribution would require gathering new information or taking a new survey. All of these uncertainties detract from the accuracy of a risk assessment or an economic impact analysis used to evaluate alternative waste management techniques.

The American Petroleum Institute's estimates: As the largest national oil trade organization, the API routinely gathers and analyzes many types of information on the oil and gas industry. In addition, in conducting its independent estimates of drilling waste volumes, API was able to conduct a direct survey of operators in 1985 to request waste volume data--a method that was unavailable to EPA because of time and funding limitations. API sent a questionnaire to a sample of operators nationwide, asking for estimated volume data for drilling muds and completion fluids, drill cuttings, and other associated wastes discharged to the reserve pit. Completed questionnaires were received for 693 individual wells describing drilling muds, completion fluids, and drill cuttings; 275 questionnaires also contained useful information concerning associated wastes. API segregated the sampled wells so that it could characterize drilling wastes within each of 11 sampling zones used in this study and within each of 4 depth classes. Since API maintains a data base on basic information on all wells drilled in the U.S., including location and depth, it was able to estimate a volume of wastes for the more than 65,000 wells drilled in 1985. The API survey does have

several significant limitations. Statistical representativeness of the survey is being analyzed by EPA. Respondents to the survey were primarily large oil companies. The survey was accompanied by a letter that may have influenced the responses. Also, EPA experience with operators indicates that they may underestimate reserve pit volumes.

Even though volumetric measurement and statistical analysis represent the preferred method for estimating drilling waste volumes, the way in which API's survey was conducted and the data were analyzed may have some drawbacks. Operators were asked to estimate large volumes of wastes, which are added slowly to the reserve pit and are not measured. Because the sample size is small in comparison to the population, it is questionable whether the sample is an unbiased representation of the drilling industry.

Estimating Volumes of Produced Water

By far the largest volume production waste from oil and gas operations is produced water. Of all the wastes generated from oil and gas operations, produced water figures are reported with the most frequency because of the reporting requirements under the Underground Injection Control (UIC) and National Pollution Discharge Elimination System (NPDES) programs.

EPA's estimates: Because produced water figures are more readily available than drilling waste data, EPA conducted a survey of the State agencies of 33 oil- and gas-producing States, requesting produced water data from injection reports, production reports, and hauling reports. For those States for which this information was not available, EPA derived estimates calculated from the oil/water ratio from surrounding States (this method used for four States) or derived estimates based on information provided by State representatives (this method used for six States).

API's estimates: In addition to its survey of drilling wastes, API conducted a supplemental survey to determine total volumes of produced water on a State-by-State basis. API sent a produced water survey form to individual companies requesting 1985 crude oil and condensate volumes and produced water volumes and distribution. Fourteen operators in 23 States responded. Because most of the operators were active in more than one State, API was able to include a total of 170 different survey points. API then used these data to generate water-to-oil ratios (number of barrels of water produced with each barrel of oil) for each operator in each State. By extrapolation, the results of the survey yield an estimate of the total volume of produced water on a statewide basis; the statewide estimated produced water volume total is simply the product of the estimated State ratio (taken from this survey) and the known total oil production for the State. API reports this survey method to have a 95 percent confidence level for produced water volumes. No standard deviation was reported with this confidence level.

For most States, the figure generated by this method agrees closely with the figure arrived at by EPA in its survey of State agencies in 33 oil-producing States. For a few States, however, the EPA and API numbers are significantly different; Wyoming is an example. Since most of the respondents to the API survey were major companies, their production operations may not be truly representative of the industry as a whole. Also, the API method did not cover all of the States covered by EPA.

Neither method can be considered completely accurate, so judgment is needed to determine the best method to apply for each State. Because the Wyoming State agency responsible for oil and gas operations believes that the API number is greatly in error, the State number is used in this report. Also, since the API survey did not cover many of the States in the Appalachian Basin, the EPA numbers for all of the Appalachian Basin States are used here. In all other cases, however, the API-produced water volume numbers, which were derived in part from a field survey, are believed to be more accurate than EPA numbers and are therefore used in this report.

Waste Volume Estimates

Drilling waste volumes for 1985, calculated by both the EPA and API methods, appear in Table II-2. Although the number of wells drilled for each State differs between the two methods, both methods fundamentally relied upon API data. The EPA method estimates that 2.44 billion barrels of waste were generated from the drilling of 64,508 wells, for an average of 37,902 barrels of waste per well. The API method estimates that 361 million barrels of waste were generated from the drilling of 69,734 wells, for an average of 5,183 barrels of waste per well. EPA has reviewed API's survey methodology and believes the API method is more reliable in predicting actual volumes generated. For the purposes of this report, EPA will use the API estimates for drilling waste volumes.

Produced water volumes for 1985, calculated by both the EPA and API methods, appear in Table II-3. The EPA method estimates 11.7 billion barrels of produced water. The API method estimates 20.9 billion barrels of produced water.

CHARACTERIZATION OF WASTES

In support of this study, EPA collected samples from oil and gas exploration, development, and production sites throughout the country and analyzed them to determine their chemical composition. The Agency designed the sampling plan to ensure that it would cover the country's wide range of geographic and geologic conditions and that it would randomly select individual sites for study within each area (USEPA 1987). One hundred one samples were collected from 49 sites in 26 different locations. Operations sampled included centralized treatment facilities, central disposal facilities, drilling operations, and production facilities. For a more detailed discussion of all aspects of EPA's sampling program, see USEPA 1987.

Table II-2 Estimated U.S. Drilling Waste Volumes, 1985

State	EPA method		API method	
	Number of wells drilled	Volume ^a 1,000 bbl	Number of wells drilled	Volume ^b 1,000 bbl
Alabama	343	15,179	367	5,994
Alaska	206	4,118	242	1,816
Arizona	3	56	3	23
Arkansas	975	43,147	1,034	8,470
California	3,038	82,276	3,208	4,529
Colorado	1,459	27,249	1,578	8,226
Florida	21	929	21	1,068
Georgia	NC ^c	NC	1	2
Idaho	NC	NC	3	94
Illinois	2,107	57,063	2,291	2,690
Indiana	910	24,645	961	1,105
Iowa	NC	NC	1	1
Kansas	5,151	96,818	5,560	17,425
Kentucky	2,141	8,683	2,482	4,874
Louisiana	4,645	205,954	4,908	46,726
Maryland	85	345	91	201
Michigan	823	22,289	870	3,866
Mississippi	568	25,136	594	14,653
Missouri	22	596	23	18
Montana	591	36,302	623	4,569
Nebraska	261	4,906	282	761
Nevada	34	1,070	36	335
New Mexico	1,694	31,638	1,780	13,908
New York	395	1,602	436	1,277
North Dakota	485	9,116	514	4,804
Ohio	3,413	13,842	3,818	8,139
Oklahoma	6,978	383,581	7,690	42,547
Oregon	5	135	5	5
Pennsylvania	2,466	10,001	2,836	8,130

Table II-2 (continued)

State	EPA method		API method	
	Number of wells drilled	Volume ^a 1,000 bbl	Number of wells drilled	Volume ^b 1,000 bbl
South Dakota	44	827	49	289
Tennessee	169	685	228	795
Texas	22,538	1,238,914	23,915	133,014
Utah	332	6,201	364	4,412
Virginia	85	345	91	201
Washington	NC ^c	NC ^c	4	15
West Virginia	1,188	4,818	1,419	3,097
Wyoming	1,409 ^d	86,546 ^d	1,497	13,528
U.S. Total	64,499	2,444,667	69,734	361,406

^a Based on total available reserve pit volume, assuming 2 ft of freeboard (ref.).

^b Based on total volume of drilling muds, drill cuttings, completion fluids, circulated cement, formation testing fluids, and other water and solids.

^c Not calculated.

^d EPA notes that for Wyoming, the State's numbers are 1,332 and 11,988,000, respectively.

Table II-3 Estimated U.S. Produced Water Volumes, 1985

State	EPA volumes		API volumes	
	1,000 bbl	Source	1,000 bbl	Source
Alabama	34,039	a	87,619	g
Alaska	112,780	b	97,740	g
Arizona	288	b	149	g
Arkansas	226,784	b	184,536	g
California	2,553,326	b	2,846,978	g
Colorado	154,255	d	388,661	g
Florida	85,052	b	64,738	g
Illinois	8,560	e	1,282,933	g
Indiana	5,846	d	--	h
Kansas	1,916,250	f	999,143	g
Kentucky	16,055	d	90,754	g
Louisiana	794,030	f	1,346,675	g
Maryland	0	b	---	h
Michigan	64,046	b	76,440	g
Mississippi	361,038	e	318,666	g
Missouri	2,177	a	--	h
Montana	159,343	b	223,558	g
Nebraska	73,411	b	164,688	g
Nevada	3,693	a	--	h
New Mexico	368,249	e	445,265	g
New York	4,918	e	--	h
North Dakota	88,529	b	59,503	g
Ohio	13,688	e	--	h
Oklahoma	1,627,390	f	3,103,433	g
Oregon	33	b	--	h
Pennsylvania	31,131	f	--	h
South Dakota	3,127	b	5,155	g
Tennessee	800	f	--	h
Texas	2,576,000	e	7,838,783	g
Utah	126,000	e	260,661	g
Virginia	0	b	--	h
West Virginia	7,327	d	2,844	g
Wyoming	253,476*	f	985,221	g
U.S. Total	11,671,641		20,873,243**	

Sources:

- a. Injection Reports
- b. Production Reports
- c. Hauling Reports
- d. Estimate calculated from water/oil ratio from surrounding States
- e. Estimate calculated from water/oil ratio from other years for which data were available
- f. Estimate calculated from information provided by State representative. See Table I-8, (Westec, 1987) to explain footnotes a-f
- g. API industry survey
- h. Not surveyed

* Wyoming states that 1,722,599,614 barrels of produced water were generated in the State in 1985. For the work done in Chapter VI, the State's numbers were used.

** Includes only States surveyed.

Central pits and treatment facilities receive wastes from numerous oil and gas field operations. Since large geographic areas are serviced by these facilities, the facilities tend to be very large; one pit in Oklahoma measured 15 acres and was as deep as 50 feet in places. Central pits are used for long-term waste storage and incorporate no treatment of pit contents. Typical operations accept drilling waste only, produced waters only, or both. Long-term, natural evaporation can concentrate the chemical constituents in the pit. Central treatment and disposal facilities are designed for reconditioning and treating wastes to allow for discharge or final disposal. Like central pits, central treatment facilities can accept drilling wastes only, produced water only, or both.

Reserve pits are used for onsite disposal of waste drilling fluids. These reserve pits are usually dewatered and backfilled. Waste byproducts present at production sites include saltwater brines (called produced waters), tank bottom sludge, and "pigging wax," which can accumulate in the gathering lines.

Extracts from these samples were prepared both directly and following the proposed EPA Toxicity Characteristic Leaching Procedure (TCLP). They were analyzed for organic compounds, metals, classical wet chemistry parameters, and certain other analytes.

API conducted a sampling program concurrent with EPA's. API's universe of sites was slightly smaller than EPA's, but where they overlapped, the results have been compared. API's methodology was designed to be comparable to that used by EPA, but API's sampling and analytical methods, including quality assurance and quality control procedures, varied somewhat from EPA's. These dissimilarities can lead to different analytical results. For a more detailed discussion of all aspects of API's sampling program, see API 1987.

Sampling Methods

Methods used by EPA and by API are discussed briefly below, with emphasis placed on EPA's program.

EPA Sampling Procedures

Pit sampling: All pit samples were composited grab samples. The EPA field team took two composited samples for each pit--one sludge sample and one supernatant sample. Where the pit did not contain a discrete liquid phase, only a sludge sample was taken. Sludge samples are defined by EPA for this report as tank bottoms, drilling muds, or other samples that contains a significant quantity of solids (normally greater than 1 percent). EPA also collected samples of drilling mud before it entered the reserve pit.

Each pit was divided into four quadrants, with a sample taken from the center of each quadrant, using either a coring device or a dredge. The coring device was lined with Teflon or glass to avoid sample contamination. This device was preferred because of its ease of use and deeper penetration. The quadrant samples were then combined to make a single composite sample representative of that pit.

EPA took supernatant samples at each of the four quadrant centers before collecting the sludge samples, using a stainless steel liquid thief sampler that allows liquid to be retrieved from any depth. Samples were taken at four evenly spaced depths between the liquid surface and the sludge-supernatant interface. EPA followed the same procedure at each of the sampling points and combined the results into a single composite for each site.

To capture volatile organics, volatile organic analysis (VOA) vials were filled from the first liquid grab sample collected. All other

sludge and liquid samples were composited and thoroughly mixed and had any foreign material such as stones and other visible trash removed prior to sending them to the laboratory for analysis (USEPA 1987).

Produced water: To sample produced water, EPA took either grab samples from process lines or composited samples from tanks. Composite samples were taken at four evenly spaced depths between the liquid surface and the bottom of the tank, using only one sampling point per tank. Storage tanks that were inaccessible from the top had to be sampled from a tap at the tank bottom or at a flow line exiting the tank. For each site location, EPA combined individual samples into a single container to create the total liquid sample for that location. EPA mixed all composited produced water samples thoroughly and removed visible trash prior to transport to the laboratory (USEPA 1987).

Central treatment facilities: Both liquid and sludge samples were taken at central treatment facilities. All were composited grab samples using the same techniques described above for pits, tanks, or process lines (USEPA 1987).

API Sampling Methods

The API team divided pits into six sections and sampled in an "S" curve pattern in each section. There were 30 to 60 sample locations depending upon the size of the pit. API's sampling device was a metal or PVC pipe, which was driven into the pit solids. When the pipe could not be used, a stoppered jar attached to a ridged pole was used. Reserve pit supernatant was sampled using weighted bottles or bottom filling devices. Produced waters were usually sampled from process pipes or valves. API did not sample central treatment facilities (API 1987).

Analytical Methods

As for sampling methods, analytical methods used by EPA and by API were somewhat different. Each is briefly discussed below.

EPA Analytical Methods

EPA analyzed wastes for the RCRA characteristics in accordance with the Office of Solid Waste test methods manual (SW-846). In addition, since the Toxicity Characteristic Leaching Procedure (TCLP) has been proposed to be a RCRA test, EPA used that analytical procedure for certain wastes, as appropriate. EPA also used EPA methods 1624 and 1625, isotope dilution methods for organics, which have been determined to be scientifically valid for this application.

EPA's survey analyzed 444 organic compounds, 68 inorganics, 19 conventional contaminants, and 3 RCRA characteristics for a total of 534 analytes. Analyses performed included gas and liquid chromatography, atomic absorption spectrometry and mass spectrometry, ultraviolet detection method, inductively coupled plasma spectrometry, and dioxin and furan analysis. All analyses followed standard EPA methodologies and protocols and included full quality assurance/quality control (QA/QC) on certain tests (USEPA 1987).

Of these 534 analytes, 134 were detected in one or more samples. For about half of the sludge samples, extracts were taken using EPA's proposed Toxicity Characteristic Leaching Procedure (TCLP) and were analyzed for a subset of organics and metals. Samples from central pits and central treatment facilities were analyzed for 136 chlorinated dioxins and furans and 79 pesticides and herbicides (USEPA 1987).

API Analytical Methods

API analyzed for 125 organics, 29 metals, 15 conventional contaminants, and 2 RCRA characteristics for each sample. The same methods were used by API and EPA for analysis of metals and conventional

pollutants with some minor variations. For organics analysis EPA used methods 1624C and 1625C, while API used EPA methods 624 and 625. While the two method types are comparable, method 1624 (and 1625C) may give a more accurate result because of less interference from the matrix and a lower detection limit than methods 624 and 625. In addition, QA/QC on API's program has not been verified by EPA. See USEPA 1987 for a discussion of EPA analytical methods.

Results

Chemical Constituents Found by EPA in Oil and Gas Extraction Waste Streams

As previously stated, EPA collected a total of 101 samples from drilling sites, production sites, waste treatment facilities, and commercial waste storage and disposal facilities. Of these 101 samples, 42 were sludge samples and 59 were liquid samples (USEPA 1987).

Health-based numbers in milligrams per liter (mg/L) were tabulated for all constituents for which there are Agency-verified limits. These are either reference doses for noncarcinogens (RfDs) or risk-specific doses (RSDs) for carcinogens. RSDs were calculated, using the following risk levels: 10^{-6} for class A (human carcinogen) and 10^{-5} for class B (probable human carcinogen). Maximum contaminant limits (MCLs) were used, when available, then RfDs or RSDs. An MCL is an enforceable drinking water standard that is used by the Office of Solid Waste when ground water is a main exposure pathway.

Two multiples of the health-based limits (or MCLs) were calculated for comparison with the sample levels found in the wastes. Multiples of 100 were used to approximate the regulatory level set by the EP toxicity test (i.e., 100 x the drinking water standards for some metals and

pesticides). Multiples of 1,000 were used to approximate the concentration of a leachate which, as a first screen, is a threshold level of potential regulatory concern. Comparison of constituent levels found by direct analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to surface waters. Comparison of constituent levels found by TCLP analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to ground water.

For those polyaromatic hydrocarbons (PAHs) for which verified health-based numbers do not exist, limits were estimated by analogy with known toxicities of other PAHs. If structure activity analysis (SAR) indicated that the PAH had the potential to be carcinogenic, then it was assigned the same health-based number as benzo(a)pyrene, a potent carcinogen. If the SAR analysis yielded equivocal results, the PAH was assigned the limit given to indeno-(1,2,3-cd) pyrene, a PAH with possible carcinogenic potential. If the SAR indicated that the PAH was not likely to be carcinogenic, then it was assigned the same number as naphthalene, a noncarcinogen.

The analysis in this chapter does not account for the frequency of detection of constituents, or nonhuman health effects. Therefore, it provides a useful indication of the constituents deserving further study, but may not provide an accurate description of the constituents that have the potential to pose actual human health and environmental risks. Readers should refer to Chapter V, "Risk Modeling," for information on human health and environmental risks and should not draw any conclusions from the analysis presented in Chapter II about the level of risk posed by wastes from oil and gas wells.

EPA may further evaluate constituents that exceeded the health-based limit or MCL multiples to determine fate, transport, persistence, and toxicity in the environment. This evaluation may show that constituents

designated as secondary in the following discussion may not, in fact, be of concern to EPA.

Although the Toxicity Characteristics Leaching Procedure (TCLP) was performed on the sludge samples, the only constituent in the leach exhibiting concentrations that exceeded the multiples previously described was benzene in production tank bottom sludge. All of the other chemical constituents that exceeded the multiples were from direct analysis of the waste.

Constituents Present at Levels of Potential Concern

Because of the limited number of samples in relation to the large universe of facilities from which the samples were drawn, results of the waste sampling program conducted for this study must be analyzed carefully. EPA is conducting a statistical analysis of these samples.

Table II-4 shows EPA and API chemical constituents that were present in oil and gas extraction waste streams in amounts greater than health-based limits multiplied by 1,000 (primary concern) and those constituents that occurred within the range of multiples of 100 and 1,000 (secondary concern). Benzene and arsenic, constituents of primary and secondary concern respectively, by this definition, were modeled in the risk assessment chapter (Chapter V). The table compares waste stream location and sample phase with the constituents found at that location and phase. Table II-5 shows the number of samples compared with the number of detects in EPA samples for each constituent of potential concern.

The list of constituents of potential concern is not final. EPA is currently evaluating the data collected at the central treatment facilities and central pits, and more chemical constituents of potential concern may result from this evaluation. Also, statistical analysis of the sampling data is continuing.

Table II-4 Constituents of Concern Found In Waste Streams Sampled by EPA and API

Chemical Constituents	Production			Central treatment			Central pit		Drilling	
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Primary concern										
Benzene	L#	S# S+	L L#		S#	L S	S#		S#	S S.
Phenanthrene		S#	L L#		S#		S#	S	S#	
Lead				S#		S#	S#		L#	L# S# S#.
Barium			L	S#	S#	S#	S#	S#	L	L# L# S# S#.
Secondary concern										
Arsenic		S	L				S			S S.
Fluoride				S			S			L S
Antimony			L							

Legend:

- L: Liquid sample > 100 x health-based number
- S: Sludge sample > 100 x health-based number
- #: Denotes > 1,000 x health-based number
- L,S: EPA samples
- L,S,: API samples
- +: TCLP extraction
- All values determined from direct samples except as denoted by "+"

Table II-5 EPA Samples Containing Constituents of Concern

	Production		Central treatment		Central pit		Drilling		
	Midpoint	Tank bottom	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Primary concern									
Benzene	L5 (3)	S1 (1) +		S2 (1)	L3 (2) S3 (1)	S3 (1)		S1 (1)	S18 (7)
Phenanthrene		S1 (1)		S2 (2)		S3 (1)		S1 (1)	
Lead			S1 (1)		S3 (3)	S3 (3)		L1 (1)	L17 (17) S21 (21)
Barium			S1 (1)	S2 (1)	S3 (3)	S3 (3)		L1 (1)	L17 (17) S21 (21)
Secondary concern									
Arsenic		S1 (1)			S3 (3)	S3 (1)			S21 (11)
Fluoride			S1 (1)		S3 (3)	S3 (3)			L17 (17) S20 (20)

Legend:
 L: Liquid sample
 S: Sludge sample
 # (#) Number of samples (number of detects)
 + TCLP extract and direct extracts

Comparison to Constituents of Potential Concern Identified in the Risk Analysis

This report's risk assessment selected the chemical constituents that are most likely to dominate the human health and environmental risks associated with drilling wastes and produced water endpoints. Through this screening process, EPA selected arsenic, benzene, sodium, cadmium, chromium VI, boron, chloride, and total mobile ions as the constituents to model for risk assessment.⁶

The chemicals selected for the risk assessment modeling differ from the constituents of potential concern identified in this chapter's analysis for at least three reasons. First, the risk assessment screening accounted for constituent mobility by examining several factors in addition to solubility that affect mobility (e.g., soil/water partition coefficients) whereas, in Chapter II, constituents of potential concern were not selected on the basis of mobility in the environment. Second, certain constituents were selected for the risk assessment modeling based on their potential to cause adverse environmental effects as opposed to human health effects; the Chapter II analysis considers mostly human health effects. Third, frequency of detection was considered in selecting constituents for the risk analysis but was not considered in the Chapter II analysis.

Facility Analysis

Constituents of potential concern were chosen on the basis of exceedances in liquid samples or TCLP extract. Certain sludge samples are listed in Tables II-4 and II-5, since these samples, through direct

⁶ Mobile ions modeled in the risk assessment include chloride, sodium, potassium, calcium, magnesium, and sulfate.

chemical analysis, indicated the presence of constituents at levels exceeding the multiples previously described. One sludge sample analyzed by the TCLP method contained benzene in an amount above the level of potential concern. This sample is included in Tables II-4 and II-5. The sludge samples are shown for comparison with the liquid samples and TCLP extract and were not the basis for choice as a constituent of potential concern. Constituents found in the liquid samples or the TCLP extract in amounts greater than 100 times the health-based number are considered constituents of potential concern by EPA.

Central Treatment Facility

Benzene, the only constituent found in liquid samples at the central treatment facilities, was found in the effluent in amounts exceeding the level of potential concern.

Central Pit Facility

No constituent was found in the liquid phase in amounts exceeding the level of potential concern at central pit facilities.

Drilling Facilities

Lead and barium were found in amounts exceeding the level of potential concern in the liquid phase of the tank bottoms and the reserve pits that were sampled. Fluoride was found in amounts that exceeded 100 times the health-based number in reserve pit supernatant.

Production Facility

Benzene was present in amounts that exceeded the level of potential concern at the midpoint and the endpoint locations. Exceedances of the

level of potential concern that occurred only at the endpoint location were for phenanthrene, barium, arsenic, and antimony. Benzene was present in amounts exceeding the multiple of 1,000 in the TCLP leachate of one sample.

WASTE CHARACTERIZATION ISSUES

Toxicity Characteristic Leaching Procedure (TCLP)

The TCLP was designed to model a reasonable worst-case mismanagement scenario, that of co-disposal of industrial waste with municipal refuse or other types of biodegradable organic waste in a sanitary landfill. As a generic model of mismanagement, this scenario is appropriate for nonregulated wastes because those wastes may be sent to a municipal landfill. However, most waste from oil and gas exploration and production is not disposed of in a sanitary landfill, for which the test was designed. Therefore, the test may not reflect the true hazard of the waste when it is managed by other methods. However, if these wastes were to go to a sanitary landfill, EPA believes the TCLP would be an appropriate leach test to use.

For example, the TCLP as a tool for predicting the leachability of oily wastes placed in surface impoundments may actually overestimate that leachability. One reason for this overestimation involves the fact that the measurement of volatile compounds is conducted in a sealed system during extraction. Therefore, all volatile toxicants present in the waste are assumed to be available for leaching to ground water. None of the volatiles are assumed to be lost from the waste to the air. Since volatilization is a potentially significant, although as yet unquantified, route of loss from surface impoundments, the TCLP may overestimate the leaching potential of the waste. Another reason for overestimation is that the TCLP assumes that no degradation--either chemical, physical, or biological--will occur in the waste before the

leachate actually leaves the impoundment. Given that leaching is not likely to begin until a finite time after disposal and will continue to occur over many years, the assumption of no change may tend to overestimate leachability.

Conversely, the TCLP may underestimate the leaching potential of petroleum wastes. One reason for this assumption is a procedural problem in the filtration step of the TCLP. The amount of mobile liquid phase that is present in these wastes and that may migrate and result in ground-water contamination is actually underestimated by the TCLP. The TCLP requires the waste to be separated into its mobile and residue solid phases by filtration. Some production wastes contain materials that may clog the filter, indicating that the waste contains little or no mobile fraction. In an actual disposal environment, however, the liquid may migrate. Thus, the TCLP may underestimate the leaching potential of these materials. Another reason for underestimation may be that the acetate extraction fluid used is not as aggressive as real world leaching fluid since other solubilizing species (e.g., detergents, solvents, humic species, chelating agents) may be present in leaching fluids in actual disposal units. The use of a citric acid extraction media for more aggressive leaching has been suggested.

Because the TCLP is a generic test that does not take site-specific factors into account, it may overestimate waste leachability in some cases and underestimate waste leachability in other cases. This is believed to be the case for wastes from oil and gas exploration and production.

The EPA has several projects underway to investigate and quantify the leaching potential of oily matrices. These include using filter aids to prevent clogging of the filter, thus increasing filtration efficiency, and using column studies to quantitatively assess the degree to which oily materials move through the soil. These projects may result in a leach test more appropriate for oily waste.

Solubility and Mobility of Constituents

Barium is usually found in drilling waste as barium sulfate (barite), which is practically insoluble in water (Considine 1974). Barium sulfate may be reduced to barium sulfide, which is water soluble. It is the relative insolubility of barium sulfate that greatly decreases its toxicity to humans; the more soluble and mobile barium sulfide is also much more toxic (Sax 1984). Barium sulfide formation from barium sulfate requires a moist anoxic environment.

The organic constituents present in the liquid samples in concentrations of potential concern were benzene and phenanthrene. Benzene was found in produced waters and effluent from central treatment facilities, and phenanthrene was found in produced waters.

An important commingling effect that can increase the mobility of nonpolar organic solvents is the addition of small amounts of a more soluble organic solvent. This effect can significantly increase the extent to which normally insoluble materials are dissolved. This solubility enhancement is a log-linear effect. A linear increase in cosolvent concentration can lead to a logarithmic increase in solubility. This effect is also additive in terms of concentration. For instance, if a number of cosolvents exist in small concentrations, their total concentration may be enough to have a significant effect on nonpolar solvents with which the cosolvents come in contact (Nkedi-Kizza 1985, Woodburn et al. 1986). Common organic cosolvents are acetone, toluene, ethanol, and xylenes (Brown and Donnelly 1986).

Other factors that must be considered when evaluating the mobility of these inorganic and organic constituents in the environment are the use of surfactants at oil and gas drilling and production sites and the

general corrosivity of produced waters. Surfactants can enhance the solubility of many constituents in these waters. Produced waters have been shown to corrode casing (see damage cases in Chapter IV).

Changes in pH in the environment of disposal can cause precipitation of compounds or elements in waste and this can decrease mobility in the environment. Also adsorption of waste components to soil particles will attenuate mobility. This is especially true of soils containing clay because of the greater surface area of clay-sized particles.

Phototoxic Effect of Polycyclic Aromatic Hydrocarbons (PAH)

New studies by Kagan et al. (1984), Allred and Giesy (1985), and Bowling et al. (1983) have shown that very low concentrations (ppb in some cases) of polycyclic aromatic hydrocarbon (PAH) are lethal to some forms of aquatic wildlife when they are introduced to sunlight after exposure to the PAHs. This is called the phototoxic effect.

In the study conducted by Allred and Giesy (1985), it was shown that anthracene toxicity to Daphnia pulex resulted from activation by solar radiation of material present on or within the animals and not in the water. It appeared that activation resulted from anthracene molecules and not anthracene degeneration products. Additionally, it was shown that wavelengths in the UV-A region (315 to 380 nm) are primarily responsible for photo-induced anthracene toxicity.

It has been shown that PAHs are a typical component of some produced waters (Davani et al., 1986a). The practice of disposal of produced waters in unlined percolation pits is allowing PAHs and other constituents to migrate into and accumulate in soils (Eiceman et al., 1986a, 1986b).

pH and Other RCRA Characteristics

Of the RCRA parameters reactivity, ignitability, and corrosivity, no waste sample failed the first two. Reactivity was low and ignitability averaged 200°F for all waste tested. On the average, corrosivity parameters were not exceeded, but one extreme did fail this RCRA test (See Table II-6). A solid waste is considered hazardous under RCRA if its aqueous phase has a pH less than or equal to 2 or greater than or equal to 12.5. As previously stated, a sludge sample is defined by EPA in this document as a sample containing a significant quantity of solids (normally greater than 1 percent).

Of the major waste types at oil and gas facilities, waste drilling muds and produced waters have an average neutral pH. Waste drilling fluid samples ranged from neutral values to very basic values, and produced waters ranged from neutral to acidic values. In most cases the sludge phase tends to be more basic than the liquid phases. An exception is the tank bottom waste at central treatment facilities, which has an average acidic value. Drilling waste tends to be basic in the liquid and sludge phases and failed the RCRA test for alkalinity in one extreme case. At production facilities the pH becomes more acidic from the midpoint location to the endpoint. This is probably due to the removal of hydrocarbons. This neutralizing effect of hydrocarbons is also shown by the neutral pH values of the production tank bottom waste. An interesting anomaly of Table II-6 is the alkaline values of the influent and effluent of central treatment facilities compared to the acidic values of the tank bottoms at these facilities. Because central treatment facilities accept waste drilling fluids and produced waters, acidic constituents of produced waters may be accumulating in tank bottom sludges. The relative acidity of the produced waters is also indicated by casing failures, as shown by some of the damage cases in Chapter IV.

Table II-6 pH Values for Exploration, Development and Production Wastes (EPA Samples)

	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Tank bottoms	Pit
Production									
Sludge		7.0; 7.0; 7.0							
Liquid	6.4; 6.6; 8.0		2.7; 7.6; 8.1						
Central treatment									
Sludge				8.8; 8.8; 8.8	2.0; 3.9; 5.8	6.7; 8.2; 10.0			
Liquid				5.7; 6.5; 7.3		7.0; 8.2; 10.1			
Central pit									
Sludge							7.2; 8.0; 9.2		
Liquid							5.7; 7.5; 8.5		
Drilling									
Sludge									6.8; 9.0; 12.8
Liquid							7.1; 7.1; 7.1		6.5; 7.7; 12.7

Legend:

#; #; # - minimum; average; maximum

Use of Constituents of Concern

The screening analysis conducted for the risk assessment identified arsenic, benzene, sodium, cadmium, chromium VI, boron, and chloride as the constituents that likely pose the greatest human health and environmental risks. The risk assessment's findings differ from this chapter's findings since this chapter's analysis did not consider the frequency of detection of constituents, mobility factors, or nonhuman health effects (see Table II-7). Some constituents found in Table II-4 were in waste streams causing damages as documented in Chapter IV.

**Table II-7 Comparison of Potential Constituents of Concern
That Were Modeled in Chapter V**

Chemical	Chapter II* V**	Reasons for not including in Chapter V risk analysis ***
Benzene	P Yes	N/A
Phenanthrene	P No	Low frequency in drilling pit and produced water samples; low ground-water mobility; relatively low concentration-to-toxicity ratio; unverified reference dose used for Chapter 2 analysis.
Lead	P No	Low ground-water mobility.
Barium	P No	Low ground-water mobility.
Arsenic	S Yes	N/A
Fluoride	S No	Relatively low concentration-to-toxicity ratio.
Antimony	S No	Low frequency in drilling pit and produced water samples.

* P = primary concern in Chapter II; S = secondary concern in Chapter II.

** Yes = modeled in Chapter V analysis; no = not modeled in Chapter V analysis.

*** Table summarizes primary reasons only; additional secondary reasons may also exist.

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